BEFORE
THE PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA
DOCKET NO. 2018-2-E

In re: Annual Review of Base Rates for Fuel Costs for South Carolina Electric & Gas Company	)	POST HEARING BRIEF

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PURSUANT TO South Carolina Public Service Commission ("Commission") Rule 103-851, intervenors South Carolina Coastal Conservation League ("CCL") and Southern Alliance for Clean Energy ("SACE") (collectively, "the Conservation Groups"), through counsel, file this brief on certain issues in the current fuel cost proceeding of South Carolina Electric & Gas Company ("SCE&G" or "Company").

I. INTRODUCTION

For many years, this annual proceeding was limited to issues of fuel cost recovery. Now, this scope has broadened to include proposed changes to current avoided cost rates, methodology, and related tariffs under the Public Utility Regulatory Policies Act of 1978[1] ("PURPA") and updates to calculations under the solar valuation methodology approved in Commission Order No. 2015-194. In this year's proceeding, the Company's requests for traditional fuel cost recovery are uncontested. In stark contrast, the Company's avoided cost proposals—particularly its proposal to completely

[1] Public Utility Regulatory Policies Act of 1978, Pub. L. No. 95-617, 92 Stat. 3117 (codified as amended in scattered sections of 15, 16, 42, and 43 U.S.C.A.) (PURPA).

eliminate capacity payments for solar power qualifying facilities ("QFs")—are challenged by nearly every other party in the proceeding.

The Company's proposals in this proceeding will directly impact the ability of low-cost solar power to compete with utility-owned generation resources to lower customer bills.

The heart of the matter is whether SCE&G is accurately compensating solar facilities, a prerequisite for allowing those solar providers to compete fairly against SCE&G-owned resources to reduce ratepayer costs, as PURPA intended. If solar power is assigned an arbitrarily low "avoided cost" value, as SCE&G has proposed, much less solar generation will emerge to compete in SCE&G's territory, blocking the use of a cost-competitive resource that will drive down customer bills. Said another way, setting avoided cost rates too low means system costs will ultimately be too high, since the artificially low avoided cost rates serve as a barrier to entry that insulates inefficient (and overpriced) resources from actually having to compete. That is why federal and state law charge this Commission with ensuring that renewable facilities are given accurate and full valuation. And that is why SCE&G's proposed avoided cost rates must be rejected.

SCE&G's claim that including an avoided capacity value in its PR-2 rates would increase costs for ratepayers is demonstrably false, and embodies a non-competitive bias that PURPA was enacted to counteract. If the Company accurately calculates the full costs that are avoided by solar resources, it can rely more heavily on cost-competitive solar purchases rather than more expensive, rate-based power plants whose costs will be passed on to customers. If avoided costs are accurately calculated, customers will be at worst held harmless by QF purchases, while enjoying other benefits of clean energy (such as decreased air pollution, protection from cost overruns of Company-built generation, and insulation from future fuel volatility) that are very real but are not quantified in avoided cost rates. This Commission should see the Company's proposals for what they are: an attempt to undermine competition. We ask that the Commission reject SCE&G's proposed methodology, and require changes that ensure full avoided cost rates in compliance with the law.

Ultimately, the Company's avoided cost proposals are unfounded, unjust, unreasonable, and discriminatory, in violation of both state law and PURPA. The errors associated with the Company's avoided cost proposals also bleed into its annual net energy metering ("NEM") methodology update, which fails to comply with the settlement agreement and Commission Order in Docket 2014-246-E. The Commission should reject the Company's avoided cost and NEM methodology proposals, particularly its proposal to eliminate avoided capacity payments for solar QFs.

As discussed below, we ask the Commission to disapprove the Company's Avoided Cost Tariffs PR-1 and PR-2 and the Company's 2018 NEM Rider to Retail Rates, requiring the Company to make revisions that shall be filed within 90 days, subject to the conditions below:

- With respect to its Avoided Capacity Calculations:
    - Recalculate capacity costs consistent with the recommendation of ORS Witness Horii, using 19.5% of the avoided cost of per kW from a 100 MW change to SCE&G's base resource plan that excludes any non-committed future resources and reflects any planned plant retirements of firm capacity;

- Include a performance adjustment factor of 1.20; and
- Include the additional revenue the Company would collect by selling marginal surplus generation capacity contracts made possible by the new qualifying facilities in the revenue requirement calculation.

- With respect to the Company's 2018 IRP and reserve margin study, the Company shall:
  - Not include as unavoidable capacity any speculative future capacity additions in its calculation of avoided costs;
  - Demonstrate that it has optimized its "base case" capacity expansion plan that it uses to develop avoided cost rates, giving reasonable consideration to alternative means of meeting capacity needs besides adding Company-owned generation; and
  - Conduct a new reserve margin study using an updated winter peak load forecast and a more widely used tool, one that balances risk and ratepayer costs, and which will be used to inform avoided cost rates in the 2019 fuel cost filing. In the interim, the Company shall retain its 2017 reserve margin of 14% and shall not adopt a 21% winter reserve margin.
- With respect to its PR-2 rate, the Company shall:
  - File a generic, technology-agnostic PR-2 rate for approval by the Commission in the current docket; and
  - In its next annual fuel cost filing, include a solar + storage rate that reflects hour-by-hour, day-by-day avoided cost rates.
- With respect to the Company's 2018 NEM Methodology Calculation update:

- The Company shall incorporate into its 2018 NEM Methodology Application the changes required to its PURPA Avoided Cost Calculations for avoided energy and avoided capacity as established above and in Ordering Paragraph 3.
- For its Avoided Line Losses calculations, the Company shall:
  - Use average annual transmission and distribution line losses weighed to a solar photovoltaic profile;
  - Calculate marginal transmission line losses as double the average line loss, as with distribution line losses;
  - Gross up avoided generation and transmission capacity calculations assigned to distribution-level DERs, including QFs, to reflect the avoided generation and transmission capacity otherwise needed to overcome line losses; and
  - Account for avoidance of 14% reserve margin assigned to generation capacity in calculating avoided line losses.
- The Company shall commission an independent study of the transmission and distribution benefits of solar QFs and file it prior to its next avoided cost filing so that it can include in its 2019 NEM Methodology application a non-zero value for the Avoided Transmission and Distribution cost component of the NEM Methodology approved in Commission Order No. 2015-194.
- The Company shall evaluate and include in its 2019 NEM Methodology application a non-zero value or estimate for the Avoided Environmental

cost component, including any avoided costs related to complying with the federal coal combustion residuals rule, of the NEM Methodology approved in Commission Order No. 2015-194.

II. LEGAL FRAMEWORK FOR DETERMING AVOIDED COSTS

A. The Commission Has Authority to Set Avoided Cost Rates Under PURPA Section 210 and Implementing Regulations.

Section 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA") requires large electric utilities to purchase available energy and capacity from small power producers, known as "qualifying facilities" or QFs. *See generally* 16 U.S.C. § 2601 *et seq.* The United States Supreme Court has declared that "Section 210 of PURPA was designed to encourage the development of cogeneration and small power production facilities." *American Paper Inst. v. Am. Elec. Power Serv. Corp.*, 461 U.S. 402, 405 (1983). As the Court explained in *FERC v. Mississippi*, "Congress believed that increased use of these sources of energy would reduce the demand for traditional fossil fuels," and it recognized that electric utilities had traditionally been "reluctant to purchase power from, and to sell power to, the nontraditional facilities." 456 U.S. 742, 750 (1982) (footnote omitted).

Under PURPA and the Federal Energy Regulatory Commission ("FERC") regulations implementing PURPA, FERC has delegated to state commissions the responsibility to set rates for purchases from qualifying cogenerators and small power producers by electric utilities under their ratemaking authority. 16 U.S.C. § 824a-3(f); *see also* Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of PURPA (Order No. 69), 45 Fed. Reg. 12214, 12215 (Feb. 25, 1980).

States exercising that authority, however, must do so within the bounds of federal law. Specifically, PURPA requires that rates for the purchase of energy from QFs by electric utilities: 1) shall be just and reasonable to the consumers of the electric utility and in the public interest, and 2) shall not discriminate against qualifying cogenerators or qualifying small power producers. 16 U.S.C. § 824a-3(b); 18 C.F.R. § 292.304(a)(1). PURPA rates are set at the utility's avoided cost of producing the next incremental unit of electricity with "incremental cost," defined as "the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source." 16 U.S.C. § 824a-3(d). FERC's PURPA implementing regulations reiterate that electric utilities are not required under PURPA to pay more for purchases than their avoided cost, 18 C.F.R. § 292.304(a)(2), defined as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source." 18 C.F.R. § 292.101(b)(6).

The PURPA regulations require electric utilities to establish standard rates for purchases from QFs with capacity of 100 kilowatts ("kW") or less, and also give state commissions the authority to develop standard rates for larger QFs. 18 C.F.R. § 292.304(c)(1), (2). These standard rates "[m]ay differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies." *Id.* at (c)(3)(ii).

Further, the PURPA regulations lay out several factors that "shall, to the extent practicable, be taken into account" when state commissions are determining avoided costs. *Id.* at (e). These include:

- Energy and capacity cost data provided pursuant to FERC regulations, including state review of any such data;
- Availability of capacity or energy from QFs during system daily and seasonal peak periods;
- Dispatchability and reliability;
- Duration and terms of contract;
- Usefulness of energy and capacity during system emergencies;
- Individual and aggregate value of energy and capacity;
- Smaller capacity increments and shorter lead times for additional capacity from QFs;
- Relationship of availability of energy and capacity from the QF to the ability of the utility to avoid costs, including deferral of capacity additions and reduction in fossil fuel use; and
- Costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a QF.

18 C.F.R. § 292.304(e)(1)-(4).

Finally, state commissions may account for the environmental costs "of all fuel sources" in determining avoided cost rates, as long as they are "real costs that would be incurred by utilities." 71 FERC 61,269, 62,080 (June 2, 1995) (citing 70 FERC 61,290, 61,676), *reconsideration denied*, 71 FERC 61,232 (1995).

B. State Law Requires Rates to Be Just and Reasonable and Requires Commission Approval of Avoided Cost Rates and the Net Energy Metering Methodology Computation.

In addition to meeting the requirements of PURPA, this Commission also holds these annual proceedings to determine utilities' avoided costs pursuant to South Carolina law. S.C. Code Ann. § 58-27-865 delegates to the Commission the responsibility to establish the "avoided costs under the Public Utility Regulatory Policy Act of 1978[.]"

S.C. Code Ann. § 58-27-865(A)(2); [2] *id.* § 58-3-140(A) (vesting the Commission with the "power and jurisdiction to supervise and regulate the rates and service of every public utility in this State . . ."). Avoided cost rates, like all rates "made, demanded or received by any electrical utility . . . shall be just and reasonable." S.C. Code Ann. § 58-27-810.

Pursuant to the Net Energy Metering ("NEM") Settlement Agreement approved previously by this Commission in Order No. 2015-194, Docket No. 2014-246-E, the Commission also approves each year the Company's calculation of the "costs and benefits of net metering and the required amount of the DER NEM Incentive" coincident in time with the Utility's filing under the fuel clause. Order No. 2015-194 at p. 22, para. (g). The DER NEM incentive is computed based on an eleven-component NEM Methodology that includes "all categories of potential costs or benefits to the Utility system that are capable of quantification or possible quantification in the future." Order 2015-194 at p. 20, para. (e).

Substantial evidence must support the Commission's avoided cost and NEM incentive decisions and the Commission must support its conclusions with factual findings that are sufficiently detailed so as to enable court review. *See Porter v. S.C. Public Service Comm'n*, 333 S.C. 12, 20 (1998); *Seabrook v S.C. Public Service Comm'n*, 401 S.E.2d 672, 674 (1991), 303 S.C. 493, 497; S.C. Code Ann. § 58-27-2100. The Commission must fully document its findings of fact and base its decision on reliable, probative, and substantial evidence on the whole record. *Porter*, 333 S.C. at 21. Further, "previously adopted policy may not furnish the sole basis for the Commission's

[2] Historically, SCE&G's PURPA avoided cost rates have been filed in Commission Docket No. 1995-1192-E; however, subsequent to Act 236 and the fuel clause revisions, SCE&G has sought approval in the fuel cost proceeding for its avoided cost rates, calculations, and methodology under Section 210 of the Public Utility Regulatory Policies Act of 1978, 16 U.S.C.A. § 824a-3.

action." *Hamm v. S.C. Public Service Comm'n*, 422 S.E. 2d 110, 114, 309 S.C. 282, 289. Rather, the policy must be applied to the substantial factual evidence of record. *Id.* Decisions of the Commission can be ruled arbitrary when it simply adheres to its past practice without attempting to explain that decision, and it cannot rely on factual findings that are simply incorrect. *Porter,* 333 S.C. at 26-27.

C. The Company's Historic Use of the Difference in Revenue Requirement Methodology.

PURPA leaves the specific methodology to be used in determining avoided cost to the states' discretion. *See California Public Utilities Comm'n*, Order Denying Rehearing, 134 FERC 61,044, 61,160 (2011) (granting state commissions the authority to decide what particular capacity is being avoided in setting avoided cost rates). This Commission has historically approved SCE&G's request to calculate its long-run avoided costs for power purchases by using a particular Difference in Revenue Requirements ("DRR") methodology. The Company's historic DRR method compared the Company's revenue requirements between a base case and a change case, over the Company's 15-year Integrated Resource Plan ("IRP") planning horizon. The base case was defined by SCE&G's "existing fleet of generators and the hourly load profile to be supplied by these generators." Docket 2017-2-E, Lynch Direct Testimony at 4, ln. 20-21. "The change case was the same as the base case except that the hourly loads were reduced by 100 megawatts ("MW") in each hour . . . ." Docket 2017-2-E, Lynch Direct Testimony at 4-5, ln. 21-22.

Other parties have contested SCE&G's use of this DRR method in prior dockets, highlighting its problematic reliance on an unapproved IRP as the basis for the proposed avoided cost rates, as well as its overly complex and opaque nature, which makes review very difficult in the limited timeframe of the fuel cost docket. *See, e.g.*, Docket 2017-2-E, SACE and CCL Petition for Rehearing or Reconsideration at p. 16-18. Parties have repeatedly suggested that SCE&G use the "peaker method" to calculate avoided cost—the method that both Duke Energy Carolinas and Duke Energy Progress already use. Nonetheless, this Commission has in previous years approved SCE&G's historic DRR method. *See* Order No. 2016-297 at p. 11-12, 20-21 (approving DRR methodology wherein SCE&G divided its calculated avoided capacity cost between summer and winter, with 80% being associated with the summer season and 20% being associated with the winter season).

In this year's fuel cost docket, the Company has proposed significant changes to the way that it implements the DRR method, which are discussed below at length. These changes do not comport with federal and state requirements.

III. <u>ARGUMENT</u>

A. The Company's proposal to eliminate capacity payments for QFs is unsupported, unjust, unreasonable, discriminatory, and not in the public interest.

The Company's proposal to completely eliminate avoided capacity payments for solar QFs violates state and federal law. Both South Carolina law and federal law require avoided cost rates to be just and reasonable. Avoided cost rates must also be non-discriminatory and in the public interest. Moreover, this Commission's decisions to approve rates must be based on substantial evidence. The Company has failed to provide the Commission with substantial evidence on this issue, and its proposal to eliminate avoided capacity payments should be rejected as unjust, unreasonable, discriminatory, and not in the public interest.

1. **The Company's refusal to compensate for capacity discriminates against QFs.**

Somewhat bizarrely, the Company claims that it is not proposing a change in methodology at all in this proceeding versus past ones, contending that it continues to use the same exact methodology that was approved by this Commission in past orders. Lynch Rebuttal at p. 2, lns. 9-10, p. 18, lns. 16-17; Hearing Tr. at E-9-11, E-95, E-176-178. The Company says that the extreme change in result is simply due to changed circumstances. Lynch Rebuttal at p. 20, lns. 8-12. But the record—including admissions from the Company's own witnesses and lawyers—overwhelmingly repudiates that assertion. The Company is in fact proposing a dramatic shift in its methodology for compensating solar QFs: the complete elimination of capacity payments. Every other party that submitted testimony in this docket strongly objects to this change as unsound, unfounded, and counterfactual, and asks that it be rejected.

SCE&G concedes that it is the Commission—not the Company—that gets to determine the methodology for avoided costs. Lynch Direct at p. 3, lns. 15-16. If seeking to alter this methodology, Company must inform the Commission and seek authority to do so. Hearing Tr. at p. E-183, lns. 9-17. The Company's witnesses and lawyers take great pains to argue that they are not changing the prior-approved methodology. In Company Witness Lynch's rebuttal testimony, for example, he states that "SCE&G is using the same methodology as in previous years and as approved by the Commission." p. 18, lns. 16-17. He claims that the zero capacity cost "is a change in result, not a change in methodology." *Id.* at p. 2, lns. 14-15; *see also id.* at p. 2, lns. 9-10: "SCE&G is using the same difference in revenue requirements ("DRR") methodology previously approved by the Commission." *See also* SCE&G's closing statement, Docket

No. 2018-2-E (reiterating that the Company is using the same methodology used in prior dockets).

The Company's attempt to convince the Commission that there is "nothing to see here" is disingenuous at best, and relies on the overly simplistic position that the Commission approves the Company's use of the DRR method *carte blanche*, without concerning itself with the myriad decisions that the Company makes about *how* to implement DRR. This is simply untrue. The Commission's past orders have made it clear that its determination of appropriate methodology extends far beyond the Company's over-arching method, be it peaker, proxy or DRR. In these orders, the Commission has addressed and resolved individually litigated issues concerning **specific elements** of the DRR method, such as the calculation of the appropriate generation capacity payment split between summer and winter seasons, Order No. 2017-246 at p. 23, the use of the number of critical peak hours in 2015 to calculate avoided capacity costs, Order No. 2016-297 at p. 20, and the reasonableness of assuming that certain future capacity can be included when calculating avoided capacity costs, Order No. 2016-297 at p. 17.

The Company concedes that Commission-approved "methodology" extends to the very changes it proposes to make in this proceeding. Under cross-examination, Witness Lynch admitted that SCE&G's decision to discontinue the 80/20 summer/winter capacity split is in fact a "pricing methodology." Hearing Tr. at p. E-183, ln. 14. This is consistent with past testimony from Witness Lynch, which unequivocally states the Company's position that past practices, such as the 80/20 capacity split, constitute methodology that was previously approved by the Commission. *See, e.g.*, Docket No. 2017-2-E Hearing

Tr. at p. E-181, Lynch Direct (stating that "consistent with the methodology approved by Commission Order No. 2016-297, SCE&G divides this avoided capacity cost between summer and winter with 80% being associated with the summer season and 20% being associated with the winter season."); Docket No. 2017-2-E Hearing Tr. at p. E-205 (referring to the 80/20 split: "this methodology was approved by the Commission in Order No. 2016-297"). The Company's lawyers also noted that SCE&G's filing in this year's docket constituted a change in methodology: ". . . the Company believed the Rate PR-2 based upon the previously approved methodology did not properly reflect SCE&G's avoided costs and therefore did not propose that rate in Docket No. 2018-2-E." Company's motion to dismiss and response in opposition to CCL and SACE's petition for an order to compel compliance, Docket No. 2017-2-E at p. 5.

Every other testifying party agrees that this is a significant change in methodology, and one that the Company fails to support. ORS Witness Horii states that "SCE&G has implemented **a dramatic change in approach** by not providing any avoided capacity cost calculations in this proceeding." Horii Direct at p. 8, ln. 6-7 (emphasis added); *see also* Horii Direct at pp. 10, 21; ORS Witness Johnson Direct at p. 5; Glick Direct at p. 6; SBA Witness Johnson Surrebuttal at pp. 2-3.

Comparison of the actual methodologies used in this and past proceedings makes this point plain. In prior years the Company has used a three step methodology where it: 1) calculated the avoided capacity value over a 15-year planning horizon comparing the difference in revenue requirements between the base case and the change case; 2) identified the set of critical peak hours where energy would have a capacity value on the system and spread the avoided capacity cost across those hours, assigning 80% of the annual capacity cost to the summer; and 3) calculated a single avoided cost value based on the production of a typical solar PV system. Glick Direct Testimony at p. 6. In contrast, in this year's docket, the Company simply assigns zero capacity value to solar, asserting that a resource must provide capacity in the winter and summer in order to provide **any** capacity value. Company Witness Lynch admits that in a departure from last year, the Company is no longer dividing avoided capacity costs between summer and winter. Instead, solar QFs receive zero payments for capacity, regardless of their capacity contribution during times of summer capacity need. Hearing Tr. at p. E-183, lns. 6-8.

Clearly, then, it is within the Commission's purview to either approve or disallow this proposed methodological change. The Commission is well within its authority to address these key components of avoided cost methodology. As evidenced by the Company's filing in this docket, even though it continues to use the DRR method, its proposed changes to underlying DRR methodology result in extreme changes to avoided cost rates—in this case, the total elimination of capacity costs.

The Commission should review and reject the Company's proposed methodological change, since the Company's refusal to compensate solar QFs for the capacity value they provide to the system is at odds with the record, and is contradicted by the Company's own IRP and by other experts' testimony in this docket. Simply, SCE&G has not met its burden to demonstrate that a payment of zero for capacity is justified.

a. <u>The record demonstrates that solar QFs can and do reduce the Company's capacity costs.</u>

It is undisputed that solar QFs can and do reduce the system's summer peaks. *See, e.g.*, Lynch Direct at pp. 17-18. For five entire months of the year, solar QFs impact peak demands on most days of the month and in all days during the months of June and July. Lynch Direct Exh. JML-4 ("On Calculating the Capacity Benefit of Solar QFs") at p. 5. Additionally, the Company has both a summer and winter capacity need over the 15-year planning period. *See* Lynch Direct at p. 23, lns. 9-10 (SCE&G's "need for capacity spans the entire year"); Hearing Tr. at p. E-189, ln. 6. It is uncontested that solar QFs will contribute to the Company's summer capacity need. In order to arrive at its conclusion that capacity payments to solar QFs are no longer appropriate, the Company asserts the illogical position that a single capacity resource must meet **both** winter and summer capacity in order to receive any capacity value at all. Under cross examination, however, Company Witness Lynch admits that this is a false choice: the Company **could** choose separate capacity resources to meet these seasonal capacity needs (for example, a winter peaking energy efficiency resource and a solar QF), and both capacity resources would in fact avoid costs. Hearing Tr. at p. E-189-190. On cross examination, in response to the question: "What would prohibit the company from choosing one capacity resource, such as a winter [demand side management] program, to meet its winter capacity need, and another capacity resource, like a solar qualifying facility, to meet its summer capacity needs?" Witness Lynch responded: "Well, I would suppose, nothing." *Id*.

b. <u>The Company's proposal is contradicted by its own IRP.</u>

The Company's 2018 IRP, which was released shortly after Witness Lynch filed his direct testimony, found that solar resources have a 35% capacity factor. Hearing Exh.

9, 2018 IRP at p. 40. This means, in SCE&G's analysis, 35% of solar's nameplate capacity is deemed by the Company to be firm capacity that is expected to serve the system summer peak. And yet, in this proceeding, the Company is requesting that solar QFs receive no compensation for capacity contributions that they make—contributions that SCE&G's own IRP acknowledges. This contradiction defies common sense.

c. <u>All other testifying parties agree that SCE&G's capacity methodology is flawed and should be rejected.</u>

ORS Witness Horii, CCL and SACE Witness Glick, and SBA Witness Johnson universally recommend that the Commission reject SCE&G's capacity methodology. According to Witness Glick, SCE&G artificially limited the future generation capacity projects or contracts that could be deferred or avoided by QFs; failed to include opportunity costs in its revenue requirements calculations; and failed to include a performance adjustment factor of 1.20. These problems yield an avoided capacity value that is too low. Witness Horii recommends that SCE&G's position of zero avoided capacity costs be rejected because SCE&G has "not adequately demonstrated that winter capacity needs are the same or greater than summer capacity needs." Horii Direct at p. 9. Witness Horii testifies that SCE&G is relying on questionable "assumptions and studies conducted in the 2018 IRP." *Id.* at 22. Finally, Witness Johnson critiques several aspects of the avoided capacity calculation, including the Company's reliance on a sub-optimal "Base" expansion plan that does not minimize revenue requirements. Johnson Direct at pp. 40, 69-70; Surrebuttal at p. 8. The Company's rebuttal to these objections is not persuasive, apparently betting that the Commission will simply endorse a new black box methodology that undervalues solar resources.

2. The Avoided Cost rates are flawed because they are based on a flawed Integrated Resource Plan.

The errors noted above are linked to the Company's 2018 Integrated Resource Plan, which the Company uses as the foundation for its avoided cost rates. At the hearing in this proceeding, the Conservation Groups raised their continuing objection to the Company's reliance on its 2018 IRP to determine avoided cost rates. State law requires substantial evidence for the Commission's decisions and requires that rates be just and reasonable. The 2018 IRP cannot be relied on as substantial evidence due the significant flaws contained in that document, including that it has not been reviewed; it fails to constitute "least cost," optimized planning; and it relies on the flawed winter peak load forecast and on a winter reserve margin that is too high. These errors in the IRP directly relate to the Company's justification for zeroing out capacity payments to QFs.

a. <u>The IRP is still being reviewed</u>

One of the core problems with the Company's approach to calculating avoided costs is that it relies on a resource plan that has no independent review or oversight. Thus, the Company has the opportunity to unilaterally change components of the IRP that materially impact avoided cost calculations in ways that benefit the Company and discriminate against independent power producers.

Although the 2018 IRP forms the basis of the Company's approach to calculating avoided costs, it was not even filed until after the Company filed its direct testimony in the current proceeding. ORS Witness Horii pointed to this problem in his direct testimony: "[SCE&G] relies upon assumptions and studies conducted in the 2018 IRP that have not been fully reviewed, vetted and/or approved by the Commission." Horii Direct at p. 21. Compounding this unreasonable reliance is the fact that the Company's resource “decisions” that it includes in its IRP are not actually binding commitments or even final decisions. In fact, Company Witness Lynch admitted at the hearing that these resource “decisions” are not decisions at all. Hearing Tr. at p. E-199, lns. 14-17. Further, the plan does not reflect optimized or least-cost resource planning: the Company did not present any results demonstrating that its proposed resource additions would be the least-cost additions, and the Company did not use any optimization or simulation software to make its long-term capacity plan. Hearing Tr. at pp. E-202-204.

Despite this, the generation additions reflected in the IRP directly drive the Company’s avoided cost rates. Hearing Tr. at p. E-200. Company Witness Lynch concedes that these non-binding IRP commitments create the foundation of costs that the Company uses as inputs to decide what actual costs a QF will avoid. *Id.* For instance, the Company has included two significant capacity additions in its IRP – a 504 MW natural gas procurement in 2018, and another 540 MW combined cycle in 2023. Lynch Direct, Exh. JML-1. However, Company Witness Lynch did not know if the Company had actually committed to the 504 MW Columbia Energy Center procurement, Hearing Tr. at p. E-200, lns. 7-8, and admitted that the Company may not build a combined cycle plant in 2023, Hearing Tr. at p. E-189-190.

Company Witness Lynch’s rebuttal testimony best illustrates the flaws with the Company’s approach. He states that “[i]f SCE&G **<u>has to</u>** build a combined-cycle unit to meet its winter peak, but which also satisfies the need for summer capacity, **then the fixed costs are incurred**. In contrast, adding solar capacity, which only has an impact on capacity in the summer, does not avoid any of those **<u>fixed costs</u>**.” Lynch Rebuttal at p. 41, lns. 19-21, p. 42, lns. 1-2 (emphases added). The Company has not in any way demonstrated that it has to, or is **even planning to,** build a 540 MW combined cycle unit in 2023. In fact, Lynch concedes that there are many ways to address winter and summer capacity needs independently. For example, demand side management resources could be used to meet rare winter peaking events while solar power is used to meet summer peak loads. Any "fixed" costs associated with the Company's hypothetical combined cycle are thus speculative and because they are clearly avoidable, some or all of them could be avoided by QFs that provide capacity to meet summer peak capacity needs. Assuming this combined cycle in the Company's "base case" is unavoidable thus arbitrarily minimizes QFs' ability to receive payment for capacity needs.

The Company cannot have it both ways: it cannot "bake in" capacity additions that it has not committed to, as a way to devalue energy and capacity from QFs, unless those additions are actual commitments that QFs can no longer avoid. The Company's claim that solar QFs will have no impact on its preferred-but-speculative resource plan answers the wrong question. The proper question is how QF power can avoid costs related to the Company's current and future capacity needs. The Commission should require the Company to answer this question without allowing the Company to place its thumb on the scales by assuming the existence of Company-built resources that are avoidable and that **should** be avoided to lower system costs.

b. <u>The Company has not optimized its plan</u>

Acknowledging the importance of these issues, FERC has addressed this very question of how utilities using the DRR method should incorporate their future capacity plans. FERC Order 69 clearly states that the evaluation of the difference between a plan with and without the QF must be done based on "the utility's optimal capacity expansion plan," and "[a]n optimal capacity expansion plan is the schedule for the addition of new generating and transmission facilities which, based on an examination of capital, fuel, operating, and maintenance costs, will meet a utility's projected load requirements at the lowest total cost." Federal Register, Vol. 45 No. 38, p. 12,216 n.6; *see also* Hearing Transcript at pp. E-211-212, p. E-212 at ln. 24-25 (Witness Lynch conceding that the Company did not use optimization software).

Company Witness Lynch agrees that the IRP should consider a range of resources. Hearing Transcript at p. E-213. He also notes that the Company makes additional showings of cost-effectiveness when it requests a certificate of convenience and public need (CPCN) from the Commission. Hearing Tr. at p. E- 199, lns. 20-24. However, as the IRP stands today, the Company concedes that it uses a simple spreadsheet model to compare generation resources – one that cannot be described as demonstrating an optimal, least cost generation plan. *Id*. at p. E-212. The Company does not use any optimization software or sophisticated modeling that could integrate various resources and select the optimal, least cost generation resources to meet future needs. *Id*. Lynch also concedes that he is not familiar with any other utility that uses an excel spreadsheet to determine its IRP capacity plan, as opposed to an optimization model such as Strategist, PROMOD, Midas, System Optimizer or AURURA. Multiple witnesses testify that SCE&G's aberrant approach is at odds with accepted industry practice, including the practice of other South Carolina utilities. *Id*. at p. E-209.

The Company admits that its spreadsheet actually analyzes only two resource options for meeting capacity needs in 2023: a peaking turbine and a combined cycle plant. Hearing Tr. at pp. E- 215-216. In response to a cross examination question about the Company's spreadsheet model, Witness Lynch states that "I think the heart of your point is, are you really moving around just combustion turbines and combined-cycles, and I'd say yes." *Id*. at pp. E-215 ln. 24 – E-216 ln. 1. The Company did not compare the cost effectiveness of these gas resources to market purchases of power, solar, energy efficiency, or battery storage. For some of these resources, the Company "baked in" a certain, pre-set amount (such as for winter demand-side management ("DSM")), but does not actually allow these resources to compete on cost against its selected 540 MW combined cycle. *Id*. The Company would also likely seek recovery of not only capacity costs related to these self-built generation additions, but also a guaranteed return on equity. *Id.* at p. E-217, ln. 8._Simply put, the Company has not demonstrated its resource plan to be "least cost," so under FERC Order 69, the resource additions in the 2018 IRP are not appropriate for the base case scenario that the Company uses to implement the DRR method.

c. <u>Winter peak load forecast</u>

The Company uses the DRR method to calculate avoided costs. This method compares results from a base case and a change case. The "base case" depends significantly on the Company's peak load forecasts and generation resources that will meet those peak load needs, both of which are taken from the 2018 IRP. As described by the Conservation Group's Witness Glick, "SCE&G's near term energy forecasts have a significant impact on avoided energy and capacity costs by driving the need for generation capacity in its resource plans." Glick Direct at p. 13. Witness Glick testifies that "SCE&G's year-on-year increase in the near term forecasted peak load [in the 2018 IRP] reflects a dramatic increase in demand, as compared to prior years' forecasts. I am concerned that this near-term jump is driving long-term planning decisions at a significant cost to ratepayers without justification." Glick Direct at p. 13. The Company further points to its winter load forecast in an effort to justify its proposal to completely eliminate avoided capacity payments for solar power. This reliance is misplaced because the Company's winter peak load forecast is flawed.

ORS Witness Horii testifies to the flaws in the Company's winter peak load forecast, specifically regarding its overstated winter season peak demand variation. "[T]he implementation of [the Company's] method is flawed because SCE&G's determination of the winter season peak demand variation is overstated." Horii Direct at p. 12. Horii goes on to explain that "SCE&G uses regression equations to estimate what peak demand would be on SCE&G's system today given the weather that occurred on historical peak days since 1991. … The winter shape [from this regression equation] has an upward curve, which is counter to engineering-based expectations. This upward curve also exacerbates the variation in peak demand, compared to the downward curve of summer predictions." Horii Direct at p. 14. As described by Witness Horii, the Company's approach goes against engineering-based expectations because the load cannot increase indefinitely with no leveling off. Eventually, "as weather becomes more extreme, "cooling [or heating, depending on the season,] equipment because more heavily used, but eventually [will] top out and cannot increase electricity usage any further." Horii Direct at p. 14. "As individual units top out, one sees diminishing increases in load as temperatures worsen." *Id*. The Company has not accounted for this leveling off of equipment usage and load in its winter season load variation analysis. The result is "an overly large estimate of winter variability for the winter season compared to the summer season." *Id.*

d. Winter reserve margin

The Company's errors in its peak load variability calculations are compounded by the extremely high reserve margin of 21% that it now proposes to use for its winter season. The Company's flawed overestimate in winter peak load forecast and variability results in the Company seeking an overly aggressive winter reserve margin, to minimize the overstated risk of being unable to meet future winter peak loads. The reserve margin is much higher than comparable utilities in the Southeast, and it was calculated using the questionable component method that is not the industry standard. *See* ORS Witness Horii Direct Testimony at 12. The Company has the capability of using a more sophisticated, industry standard approach, but it declined to do so. In so doing, the Company has not only artificially limited avoided cost payments for QFs, but also seeks to add unneeded winter capacity generation that will increase costs for customers. Hearing Tr. at p. E-241.

A comparison of other winter reserve margins in the Southeast demonstrates that the Company's proposed reserve margin is unreasonable. Witness Glick testifies that "[r]egional peer utilities such as Duke and Southern Company use a different, more comprehensive methodology that balances physical reliability and customer costs." Glick Direct at p. 10. In contrast to the Company's proposed 21% reserve margin, Southern Company and Duke have 17% reserve margins, with the aim of "balanc[ing] reliability and cost minimization." Glick Direct at p. 11. Company Witness Lynch attempts to point to other regional examples of high winter reserve margins from PJM and a Florida utility. But ORS Witness Horii rebuts Lynch's efforts in surrebuttal, in particular pointing out that Lynch's statement is "misleading" and that the PJM figure cited by Lynch is not at all analogous to a reserve margin. Horii Surrebuttal at pp. 8-9.

SCE&G is capable of using a more sophisticated approach to determining its winter reserve margin. Indeed, the Company used a Loss of Load Probability Method in 2012. The Company even described the LOLP method as the "traditional and industry standard technique" in its 2013 IRP. Hearing Tr. at pp. E-240-241. Yet the Company unreasonably declined to use the LOLP method to inform its new reserve margin study.

Company Witness Lynch admits that its proposed winter reserve margin is largely responsible for the Company's proposal to completely eliminate avoided capacity payments to QFs. Hearing Tr. at p. E- 201. Given the flaws in this winter reserve margin study, the Company has not met its burden of demonstrating that a 21% winter reserve margin is appropriate, and this study should not be allowed to inform avoided cost rates.

3. SCE&G's zero capacity payment violates PURPA.

FERC's regulations implementing PURPA are very clear: they state that "[e]ach electric utility **shall purchase**, in accordance with §292.304 . . . **any** energy and **capacity** which is made available from a qualifying facility." 18 C.F.R. § 292.303(a) (emphasis added). These rates must reflect the cost that the purchasing utility **<u>can avoid</u>** as a result of obtaining energy and capacity from these sources. 18 C.F.R. § 292.101(b)(6).

Order 69 acknowledges that different types of QFs may provide different capacity values, and it describes aggregating capacity for certain renewable QFs. While FERC indicated that a single intermittent QF might not permit the purchasing utility to avoid constructing or reserving capacity, "the aggregate capacity value of such facilities must be considered in the calculation of rates for purchases, and the payment distributed to the class providing the capacity." Order No. 69, *Small Power Production and Cogeneration*

Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978, 45 FR 12214, 12225 (1980). FERC continued,

> Some technologies, such as photovoltaic cells, although subject to some uncertainty in power output, have the general advantage of providing their maximum power coincident with the system peak when used on a summer peaking system. The value of such power is greater to the utility than power delivered during off-peak periods. Since the need for capacity is based, in part, on system peaks, the qualifying facility's coincidence with the system peak should be reflected in the allowance of some capacity value and an energy component that reflects the avoided energy costs at the time of the peak.
> *Id*.

FERC has stated in past orders that an avoided cost rate need not include capacity costs where a QF does not "permit the purchasing utility to avoid the need to construct a generating unit, to build a smaller, less expensive plant, or to reduce firm power purchases from another utility." *City of Ketchikan, Alaska Copper Valley Elec. Ass'n, Inc.; City of Petersburg, Alaska; & City of Wrangell, Alaska*, 94 FERC ¶ 61293 (Mar. 15, 2001), *quoting* Order No. 69, FERC Stats. & Regs., Regs. Preambles 1977-1981 ¶ 30,128 at 30,865.

The Company has not demonstrated that it has met any of these preconditions for waiving its obligation to pay QFs for capacity. In fact, based on the record, the opposite is true: the Company concedes that it may **not** in fact build a combined cycle plant in 2023; that it **could** opt to invest in winter-peaking demand response programs that would alleviate winter peaks, allowing it to meet remaining summer capacity needs with solar QFs. Hearing Tr. at pp. E-189-190. The Company appears to be attempting to rig its avoided cost methodology to reach its intended result: zeroing out capacity payments to its competitors, and justifying additional, and unnecessary, self-built capacity in future years. *See* Lynch Rebuttal p. 41, lns 19-21, p. 42, lns 1-2. Its changes to its winter reserve margin, winter peak load, capacity methodology, and QF pricing methodology all appear intended to meet this self-serving result. Clearly, SCE&G has not met its burden to demonstrate that solar QFs' capacity **cannot** be used to meet its "total system load." Order No. 69, FERC Stats. & Regs., Regs. Preambles 1977-1981 ¶ 30,128 at 30,870. Since a summer capacity need exists over the next 15 years, and because SCE&G has not **actually demonstrated** that QFs will not permit the utility to avoid building or buying future capacity, it has an obligation under PURPA to pay QFs fairly for the capacity that they provide. See also *Hydrodynamics Inc.*, 146 FERC ¶ 61193 (2014) (rejecting a utility's attempt to eliminate capacity payments for certain QFs where the utility failed to establish "any clear relationship to . . . actual demand for capacity").

B. Rates for Non-Solar QFs

The Company has further erred in its limitation of PR-2 rates to only solar facilities. Under SCE&G's proposal, QFs not eligible for the new tariff—for example, wind, biomass, or cogeneration QFs, or solar QFs with storage batteries—would not have access to standard rates and would be required to negotiate avoided cost rates and a power purchase agreement with the Commission. Lynch Direct at pp. 7-8, 19. Company Witness Lynch rationalizes that it must set out a solar-specific rate given the additional 865 MW of solar QFs under contract to deliver power to the Company, and given that it has successfully negotiated contracts with non-solar facilities in the past without a rate in place. *Id*. However, at the hearing, Company Lynch acknowledged that the proposed PR-2 rate is not appropriate for and does not incentivize the addition of non-solar QFs. Hearing Tr. at p. E-55. Furthermore, he acknowledged that in the 35 years during which the Company negotiated contracts with such facilities when there was no tariff set, just one QF obtained a contract with the Company. Hearing Tr. at p. E-56, lns. 6-7.

Both ORS Witness Horii and SBA Witness Johnson criticized the Company's failure to offer a technology agnostic PR-2 rate for non-solar facilities. Horii Direct at p. 9; Johnson Surrebuttal at p. 32. Witness Horii critiqued the Company's failure to produce calculations of long-run avoided costs for non-solar QF resources in part because this failure made it impossible to understand what capacity values would have been.

The Company has not demonstrated that it is appropriate to eliminate its technology-agnostic PR-2 rate. Negotiated rates are not an appropriate alternative to well-designed, technology-agnostic standard offer tariffs. Johnson Surrebuttal at p. 34. This is especially true because SCE&G has demonstrated its willingness to eliminate capacity payments for QFs. For example, Witness Lynch testifies that SCE&G "does not believe there will ever be enough capacity from [] small non-solar QFs to affect its resource plan and, therefore, the avoided capacity costs for PR-1 are zero." Lynch Direct Testimony at 22. The Commission and parties in this docket have reason to suspect that the Company would push for such values in its private negotiations, in violation of PURPA and its requirements that "[e]ach electric utility shall purchase, in accordance with §292.304…any energy and capacity which is made available from a qualifying facility." 18 C.F.R. § 292.303(a). These rates must reflect the cost that the purchasing utility can avoid as a result of obtaining energy and capacity from these sources. 18 C.F.R. § 292.101(b)(6).

The Commission has previously held that it is reasonable to offer standard PR-2 rates to all QFs, regardless of their output characteristics. Order No. 2017-246 at pp. 17-

18. The Commission should continue to require SCE&G to offer technology agnostic rates, and should also incentivize energy storage technologies that could increase solar resources' value to the Company's system.

C. The Company's 2018 NEM Methodology update fails to comply with the 2014 settlement agreement approved by this Commission.

By failing to include non-zero values for several components that are reasonably quantifiable, the Company is in violation of the 2014 settlement agreement approved by this Commission. The NEM Settlement approved previously by this Commission in Order No. 2015-194, Docket No. 2014-246-E, requires an annual update to the calculation of "costs and benefits of net metering." Order 2015-194 at p. 22, para. (g). The NEM Methodology includes eleven components and the settlement directs that the values for such components will be filled in as capabilities to reasonably quantify those components become available. Order 2015-194 at p. 20, para. (e). Regarding avoided capacity specifically, the settlement defines avoided capacity as the increase or reduction in fixed costs to the utility "of building and maintaining new conventional generation resources associated with the adoption of NEM." Order 2015-194 at p. 8.

For several years now, the Conservation Groups have raised the concern that there are components within the NEM Methodology that are capable of quantification but that have not been included in the Company's annual update. This is still the case in 2018. In particular, Witness Glick testifies for the Conservation Groups that the avoided transmission and distribution ("T&D") capacity component and avoided environmental cost component are capable of reasonable quantification at this time, and she testifies that the avoided line loss values should be updated. *See* Glick Direct at pp. 22-32. The problem with including zero values for the annual update is more pronounced this year as the Company has now also proposed to include a zero value for avoided capacity benefits. The Commission should require the Company to include a non-zero avoided capacity value in the NEM Methodology update consistent with requiring this value to be calculated for the PURPA avoided costs.

On avoided T&D costs, Witness Glick provides an exhibit with nearly 40 specific T&D values from other states that demonstrate the ability to reasonably calculate this component. ORS Witness Horii similarly acknowledges that other jurisdictions recognize avoided T&D capacity benefits of distributed energy resources. Horii Direct at 24. As admitted on cross examination, Witness Horii even co-authored a report, *Avoided Cost 2016 Interim Update*, for California utilities that quantified T&D costs that were avoided by distributed energy resources.[3] The Company argues that any deferral of avoided T&D capacity is basically "noise" on the system. Lynch Direct at p. 28, Rebuttal at p. 25, ln. 16. However, even if this value is small, that should not excuse the Company from calculating and including it in its annual updates.

Witness Glick testifies to several recommendations for improving the Company's avoided line loss calculations. Her recommendations include 1) using an average annual T&D losses weighed to a PV profile, 2) doubling the average line loss for transmission line losses, 3) grossing up avoided generation and transmission capacity calculations assigned to distribution-level distributed energy resources to reflect the avoided generation and transmission capacity otherwise needed to overcome line losses, and 4) reflecting the avoidance of the reserve margin in line loss calculations. Glick Direct at

[3] Notably, this report also quantified ancillary services costs avoided by distributed energy resources. Ancillary services is another NEM Methodology component that the Company has failed to provide a value for in the annual updates.

31. In rebuttal, the Company largely argues that the Commission has previously approved its approach to line losses in Order 2017-246. Lynch Rebuttal at 25-34. However, this previous ruling is not binding on the Commission, and indeed it must not make a determination based solely on its previous decisions. *Hamm v. S.C. Public Service Comm'n*, 422 S.E. 2d 110, 114, 309 S.C. 282, 289 (1992); *Porter v. S.C. Public Service Comm'n*, 333 S.C. 12, 26-27 (1998).

On avoided environmental costs, Witness Glick testifies that there are environmental costs beyond those included in the Company's avoided energy costs that should be accounted for. She specifically points to costs of complying with the Environmental Protection Agency's final rule on coal combustion residuals ("CCR"). As explained in Glick's testimony, "NEM resources will result in the reduced dispatch of SCE&G's coal units," implicating less CCR generation and the ability to delay or avoid construction of new ash ponds or other CCR facilities. Glick Direct at 32. In his surrebuttal testimony and at the hearing, Witness Lynch modified the 2018 NEM update to separate out avoided environmental costs from the avoided energy component of its annual update. However, Witness Lynch did not account for the CCR costs that Witness Glick raised in her testimony.

The Company's annual update this year poses an additional problem in that it has proposed a zero value for avoided capacity. The plain language of the settlement agreement says that avoided capacity component is the *increase or reduction in fixed costs to the utility of building and maintaining new conventional generation resources* associated with the adoption of NEM. Order 2015-194 at p. 8 (emphasis added). The Company's error of assigning net-metered DERs a zero capacity value is inconsistent with a plain reading of the settlement because it means that these NEM resources have no ability to avoid new capacity.

Requested Relief

In light of the significant errors made by the Company in its filing, we ask the Commission to disapprove the Company's Avoided Cost Tariffs PR-1 and PR-2 and the Company's 2018 NEM Rider to Retail Rates, requiring the Company to make revisions that shall be filed within 90 days, subject to the conditions below:

- With respect to its Avoided Capacity Calculations:
  - Recalculate capacity costs consistent with the recommendation of ORS Witness Horii, using 19.5% of the avoided cost of per kW from a 100 MW change to SCE&G's base resource plan that excludes any non-committed future resources and reflects any planned plant retirements of firm capacity;
  - Include a performance adjustment factor of 1.20; and
  - Include the additional revenue the Company would collect by selling marginal surplus generation capacity contracts made possible by the new qualifying facilities in the revenue requirement calculation.
- With respect to the Company's 2018 IRP and reserve margin study, the Company shall:
  - Not include as unavoidable capacity any speculative future capacity additions in its calculation of avoided costs;

- Demonstrate that it has optimized its "base case" capacity expansion plan that it uses to develop avoided cost rates, giving reasonable consideration to alternative means of meeting capacity needs besides adding Company-owned generation; and
- Conduct a new reserve margin study using an updated winter peak load forecast and a more widely used tool, one that balances risk and ratepayer costs, and which will be used to inform avoided cost rates in the 2019 fuel cost filing. In the interim, the Company shall retain its 2017 reserve margin of 14% and shall not adopt a 21% winter reserve margin.

- With respect to its PR-2 rate, the Company shall:
  - File a generic, technology-agnostic PR-2 rate for approval by the Commission in the current docket; and
  - In its next annual fuel cost filing, include a solar + storage rate that reflects hour-by-hour, day-by-day avoided cost rates.
- With respect to the Company's 2018 NEM Methodology Calculation update:
  - The Company shall incorporate into its 2018 NEM Methodology Application the changes required to its PURPA Avoided Cost Calculations for avoided energy and avoided capacity as established above in Ordering Paragraph 3.
  - For its Avoided Line Losses calculations, the Company shall:
    - Use average annual transmission and distribution line losses weighed to a solar photovoltaic profile;

- Calculate marginal transmission line losses as double the average line loss, as with distribution line losses;
- Gross up avoided generation and transmission capacity calculations assigned to distribution-level DERs, including QFs, to reflect the avoided generation and transmission capacity otherwise needed to overcome line losses; and
- Account for avoidance of 14% reserve margin assigned to generation capacity in calculating avoided line losses.

o The Company shall commission an independent study of the transmission and distribution benefits of solar QFs and file it prior to its next avoided cost filing so that it can include in its 2019 NEM Methodology application a non-zero value for the Avoided Transmission and Distribution cost component of the NEM Methodology approved in Commission Order 2015-194.

o The Company shall evaluate and include in its 2019 NEM Methodology application a non-zero value or estimate for the Avoided Environmental cost component, including any avoided costs related to complying with the federal coal combustion residuals rule, of the NEM Methodology approved in Commission Order 2015-194.

Respectfully submitted this 19th day of April, 2018.

s/ J. Blanding Holman, IV

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